LoopNet, Inc.
Form 4
December 18, 2007

FORM 4

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

OMB APPROVAL

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Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Boyle Richard J Jr

(Last) (First) (Middle)

C/O LOOPNET, INC., 185 BERRY STREET, SUITE 4000

(Street)

SAN FRANCISCO, CA 94107

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
LoopNet, Inc. [LOOP]

3. Date of Earliest Transaction (Month/Day/Year)
12/17/2007

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director
_____ 10% Owner
__X__ Officer (give title below)
_____ Other (specify below)
Chief Executive Officer

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	12/17/2007		S(1)		70	D	$ 13.7285	1,134,145	I	The Boyle Family Trust
Common Stock	12/17/2007		S(1)		563	D	$ 13.73	1,133,582	I	The Boyle Family Trust
Common Stock	12/17/2007		S(1)		141	D	$ 13.74	1,133,441	I	The Boyle Family Trust
Common Stock	12/17/2007		S(1)		141	D	$ 13.75	1,133,300	I	The Boyle Family

									Trust
Common Stock	12/17/2007		S(1)		71	D	$ 13.76	1,133,229	I	The Boyle Family Trust
Common Stock	12/17/2007		S(1)		35	D	$ 13.77	1,133,194	I	The Boyle Family Trust
Common Stock	12/17/2007		S(1)		71	D	$ 13.78	1,133,123	I	The Boyle Family Trust
Common Stock	12/17/2007		S(1)		71	D	$ 13.79	1,133,052	I	The Boyle Family Trust
Common Stock	12/17/2007		S(1)		71	D	$ 13.8	1,132,981	I	The Boyle Family Trust
Common Stock	12/17/2007		S(1)		71	D	$ 13.88	1,132,910	I	The Boyle Family Trust
Common Stock								133,638	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Owne Follo Repo Trans (Instr
								Date Exercisable	Expiration Date	Title	Amount or Number of Shares		
				Code	V	(A)	(D)						

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Boyle Richard J Jr C/O LOOPNET, INC. 185 BERRY STREET, SUITE 4000 SAN FRANCISCO, CA 94107	X		Chief Executive Officer	

Signatures

/s/ Maria Valles as Attorney-in-Fact	12/18/2007
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) The sales reported in this Form 4 were effected pursuant to a Rule 10b5-1 trading plan adopted by the reporting person when not in possession of material non-public information.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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2010

2009

(unaudited)

(unaudited)

REVENUES

Supply & Logistics segment revenues	$ 6,179	$ 4,645	$ 17,992	$ 11,876

Transportation segment revenues	
	144
	147
	421
	401
Facilities segment revenues	
	91
	65
	249
	165
Total revenues	
	6,414
	4,857
	18,662

Explanation of Responses:

12,442

COSTS AND EXPENSES

Purchases and related costs

5,971

4,417

Explanation of Responses:

17,233

11,036

Field operating costs

176

163

510

474

General and administrative expenses

56

52

174

153

Depreciation and amortization

61

59

192

173

Total costs and expenses

6,264

4,691

18,109

11,836

OPERATING INCOME

150

166

553

606

OTHER INCOME/(EXPENSE)

Equity earnings in unconsolidated entities

1

5

3

13

Interest expense (net of capitalized interest of $4, $4, $13 and $9, respectively)

(64

)

(59

)

(183

)

(165

)

Other income/(expense), net

(7

)

12

(9

Explanation of Responses:

)

17

INCOME BEFORE TAX

80

124

364

471

Current income tax benefit/(expense)

1

(2

Explanation of Responses:

)

(5

)

Deferred income tax benefit

3

4

4

NET INCOME

84

Explanation of Responses:

122

368

470

Less: Net income attributable to noncontrolling interests

(3

)

(5

)

(1

)

NET INCOME ATTRIBUTABLE TO PLAINS:

$

81

$

122

$

363

$

469

NET INCOME ATTRIBUTABLE TO PLAINS:

LIMITED PARTNERS

$

40

$	88
$	241
$	370

GENERAL PARTNER

$	41
$	34
$	122
$	99

BASIC NET INCOME PER LIMITED PARTNER UNIT

$	0.28
$	0.65
$	1.73
$	2.84

DILUTED NET INCOME PER LIMITED PARTNER UNIT

$	0.28
$	0.65
$	1.72
$	2.82

BASIC WEIGHTED AVERAGE UNITS OUTSTANDING

	136

130
136
128

DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING

137
131
137
129

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Nine Months Ended September 30, 2010	2009
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 368	$ 470
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	192	173
Equity compensation charge	50	47
Gain on sale of linefill	(18)	(4)
Loss on early redemption of senior notes (Note 5)	6	
Other		(39)
Changes in assets and liabilities, net of acquisitions	(135)	(300)
Net cash provided by operating activities	463	347
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(197)	(117)
Additions to property, equipment and other	(323)	(354)
Cash received for sale of noncontrolling interest in a subsidiary	268	26
Net cash received for linefill	20	8
Investment in unconsolidated entities		(4)
Other investing activities	5	4
Net cash used in investing activities	(227)	(437)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on Plains revolving credit facility	(281)	(454)
Net borrowings on PNG revolving credit facility	222	
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	100	(180)
Repayment of PNGS debt		(446)
Repayments of senior notes	(175)	(175)
Net proceeds from the issuance of senior notes	400	1,346
Net proceeds from the issuance of common units		458
Distributions paid to common unitholders (Note 7)	(382)	(344)
Distributions paid to general partner (Note 7)	(125)	(98)
Distributions to noncontrolling interests (Note 7)	(5)	
Other financing activities	(1)	(9)
Net cash provided by/(used in) financing activities	(247)	98
Effect of translation adjustment on cash	(1)	(3)
Net increase/(decrease) in cash and cash equivalents	(12)	5
Cash and cash equivalents, beginning of period	25	11
Cash and cash equivalents, end of period	$ 13	$ 16
Cash paid for interest, net of amounts capitalized	$ 191	$ 150
Cash paid for income taxes, net of amounts refunded	$ 20	$ 7

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in millions)

	Common Units		General Partner	Partners Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Partners Capital
	Units	Amount				
				(unaudited)		
Balance, December 31, 2009	136	$ 4,002	$ 94	$ 4,096	$ 63	$ 4,159
Net income		241	122	363	5	368
Sale of noncontrolling interest in a subsidiary (Note 7)		99	2	101	167	268
Distributions (Note 7)		(382)	(125)	(507)	(5)	(512)
Issuance of common units under LTIP (Note 7)		16		16		16
Other comprehensive income		36	1	37		37
Other		2	3	5	2	7
Balance, September 30, 2010	136	$ 4,014	$ 97	$ 4,111	$ 232	$ 4,343

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(unaudited)		(unaudited)	
Net income	$ 84	$ 122	$ 368	$ 470
Other comprehensive income	17	210	37	57
Comprehensive income	101	332	405	527
Less: Comprehensive income attributable to noncontrolling interests	(3)		(5)	(1)
Comprehensive income attributable to Plains	$ 98	$ 332	$ 400	$ 526

CONDENSED CONSOLIDATED STATEMENT OF

CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
		(unaudited)		
Balance, December 31, 2009	$ 18	$ 106	$ (1)	$ 123

Reclassification adjustments		11						11
Net deferred loss on cash flow hedges		(6)						(6)
Currency translation adjustment				32				32
Total period activity		5		32				37
Balance, September 30, 2010	$	23	$	138	$	(1)	$	160

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Basis of Presentation

Organization

We engage in the transportation, storage, terminalling and marketing of crude oil, refined products and LPG. We also engage in the development and operation of natural gas storage facilities. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 11 for further detail of our operating segments.

As used in this Form 10-Q, the terms Partnership, Plains, PAA, we, us, our, ours and similar terms refer to Plains All American Pipelin and its subsidiaries, unless the context indicates otherwise. References to our general partner, as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC.

Definitions

The following additional defined terms are used in this Form 10-Q and shall have the meanings indicated below:

AOCI	= Accumulated other comprehensive income
API 653	= American Petroleum Institute Standard 653
Bcf	= Billion cubic feet
CAA	= Clean Air Act
CAD	= Canadian Dollar
DCP	= Disclosure controls and procedures
DERs	= Distribution Equivalent Rights
DOJ	= United States Department of Justice
EPA	= United States Environmental Protection Agency
FERC	= Federal Energy Regulation Commission
FASB	= Financial Accounting Standards Board
ICE	= IntercontinentalExchange

IPO	= Initial Public Offering
LIBOR	= London Interbank Offered Rate
LPG	= Liquefied petroleum gas and other natural gas-related petroleum products
LTIP	= Long term incentive plan
Mcf	= Thousand cubic feet
MLP	= Master limited partnership
MTBE	= Methyl tertiary-butyl ether
NJDEP	= New Jersey Department of Environmental Protection
NYMEX	= New York Mercantile Exchange
NPNS	= Normal purchase and normal sale
PAA Class B units	= Class B units of our general partner, Plains AAP, L.P.
PLA	= Pipeline loss allowance
PNG	= PAA Natural Gas Storage, L.P.
PNG Class B units	= Class B units of PNG s general partner, PNGS GP LLC
PNG Plan	= PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan
PNGS	= PAA Natural Gas Storage, LLC
PAT	= Pacific Atlantic Terminals, LLC
Rainbow	= Rainbow Pipe Line Company Ltd.
RMPS	= Rocky Mountain Pipeline System
SEC	= Securities and Exchange Commission
U.S. GAAP	= United States generally accepted accounting principles
USD	= United States Dollar
WTI	= West Texas Intermediate

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Basis of Consolidation and Presentation

The accompanying condensed consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2009 Annual Report on Form 10-K. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the SEC. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income attributable to Plains. The condensed balance sheet data as of December 31, 2009 was derived from audited financial statements, but does not include all disclosures required by U.S. GAAP. The results of operations for the three and nine months ended September 30, 2010 should not be taken as indicative of the results to be expected for the full year.

Subsequent events have been evaluated through the financial statements issuance date and have been included within the following footnotes where applicable.

Note 2 Recent Accounting Pronouncements

Other than as discussed below and in our 2009 Annual Report on Form 10-K, no new accounting pronouncements have become effective during the nine months ended September 30, 2010 that are of significance or potential significance to us.

Fair Value Measurement Disclosure Requirements. In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. A fair value measurement is designated as Level 1, 2 or 3 within the hierarchy based on the nature of the inputs used in the valuation process. Level 1 measurements generally reflect quoted market prices in active markets for identical assets or liabilities, Level 2 measurements generally reflect the use of significant observable inputs and Level 3 measurements typically utilize significant unobservable inputs. This new guidance requires additional disclosures regarding transfers into and out of Level 1 and Level 2 measurements and requires a gross presentation of activities within the Level 3 roll forward. This guidance was effective for the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. We adopted the guidance relating to Level 1 and Level 2 measurements as of January 1, 2010. Our adoption did not have any material impact on our financial position, results of operations or cash flows. We will adopt the guidance relating to Level 3 measurements on January 1, 2011. We do not expect that adoption of this guidance will have any material impact on our financial position, results of operations, or cash flows.

Variable Interest Entities. In June 2009, the FASB issued guidance that requires an enterprise to perform an analysis to determine whether the enterprise s variable interest(s) provide a controlling financial interest in a variable interest entity (VIE). This analysis identifies the primary beneficiary of a VIE as the enterprise that has (i) the power to direct the activities of a VIE that most significantly impact the entity s economic performance and (ii) the obligation to absorb losses of the entity, or the right to receive benefits from the entity, that could potentially be significant to the VIE. This guidance also (i) requires such assessments to be ongoing, (ii) amends certain guidance for determining whether an entity is a VIE and (iii) enhances disclosures that will provide users of financial statements with more transparent information regarding an enterprise s involvement in a VIE. We adopted this guidance as of January 1, 2010. Our adoption did not have any material impact on our financial position, results of operations or cash flows.

Note 3 Trade Accounts Receivable

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At September 30, 2010 and December 31, 2009, substantially all of our accounts receivable (net of allowance for doubtful accounts) were less than 60 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $4 million and $9 million at September 30, 2010 and December 31, 2009, respectively. The decrease in our allowance for doubtful accounts receivable balance during the nine months ended September 30, 2010 primarily is due to the collection and related settlement of claims for receivables that had been reserved for during the years ended December 31, 2009 and 2008. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

At September 30, 2010 and December 31, 2009, we had received approximately $142 million and $212 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements (contractual agreements that allow us and the counterparty to offset receivables and payables between the two) that cover a significant part of our transactions and also serve to mitigate credit risk.

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Note 4 Inventory, Linefill, Base Gas and Long-term Inventory

Inventory, linefill, base gas and long-term inventory consisted of the following (barrels in thousands, natural gas volumes in millions and total value in millions):

	September 30, 2010				December 31, 2009			
	Volumes	Unit of Measure	Total Value	Price/ Unit (1)	Volumes	Unit of Measure	Total Value	Price/ Unit (1)
Inventory								
Crude oil	14,556	barrels	$ 1,066	$ 73.23	12,232	barrels	$ 886	$ 72.43
LPG	9,627	barrels	462	$ 47.99	6,051	barrels	247	$ 40.82
Refined products	300	barrels	25	$ 83.33	283	barrels	21	$ 74.20
Natural gas (2)	114	mcf	1	$ 3.58	181	mcf	1	$ 3.30
Parts and supplies	N/A		2	N/A	N/A		2	N/A
Inventory subtotal			1,556				1,157	
Linefill and base gas								
Crude oil	9,166	barrels	468	$ 51.06	9,404	barrels	471	$ 50.09
Natural gas (2)	11,194	mcf	38	$ 3.39	9,194	mcf	28	$ 3.04
LPG	77	barrels	4	$ 51.95	52	barrels	2	$ 38.46
Linefill and base gas subtotal			510				501	
Long-term inventory								
Crude oil	1,420	barrels	97	$ 68.31	1,497	barrels	103	$ 68.80
LPG	544	barrels	23	$ 42.28	458	barrels	18	$ 39.30
Long-term inventory subtotal			120				121	
Total			$ 2,186				$ 1,779	

(1) Price per unit represents a weighted average associated with various grades, qualities, and locations; accordingly, these prices may not be comparable to published benchmarks for such products.

(2) The volumetric ratio of mcf of natural gas to barrels of crude oil is 6:1; thus, natural gas volumes can be converted to barrels by dividing by 6.

Note 5 Debt

Debt consisted of the following (in millions):

	September 30, 2010	December 31, 2009
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 2.5% at both September 30, 2010 and December 31, 2009	$ 400	$ 300
Senior unsecured revolving credit facility, bearing interest at a rate of 0.7% and 0.8% at September 30, 2010 and December 31, 2009, respectively (1)	493	772
Other	2	2
Total short-term debt	895	1,074
Long-term debt:		
4.25% senior notes due September 2012 (2)	500	500
7.75% senior notes due October 2012	200	200
5.63% senior notes due December 2013	250	250
5.25% senior notes due June 2015	150	150
3.95% senior notes due September 2015 (3)	400	
6.25% senior notes due September 2015 (4)		175
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	350
5.75% senior notes due January 2020	500	500
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized discount	(13)	(14)
Long-term debt under credit facilities and other (5)	231	6
Total long-term debt (1) (6)	4,593	4,142
Total debt	$ 5,488	$ 5,216

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(1) We classify as short-term our borrowings under our senior unsecured revolving credit facility. These borrowings are designated as working capital borrowings, must be repaid within one year and are primarily for hedged LPG and crude oil inventory and NYMEX and ICE margin deposits.

(2) These notes were issued in July 2009 and the proceeds are being used to supplement capital available from our hedged inventory facility. At September 30, 2010 and December 31, 2009, approximately $500 million and $222 million, respectively, had been used to fund hedged inventory and would be classified as short-term debt if funded on our credit facilities.

(3) In July 2010, we completed the issuance of $400 million of 3.95% senior notes due September 15, 2015. The senior notes were sold at 99.889% of face value. Interest payments are due on March 15 and September 15 of each year, beginning on September 15, 2010. We used the net proceeds from this offering to repay outstanding indebtedness under our credit facilities.

(4) On September 15, 2010, our $175 million, 6.25% senior notes due 2015 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $6 million. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

(5) In April 2010, our consolidated subsidiary PNG entered into a three year, $400 million senior unsecured revolving credit facility that matures in May 2013. This credit facility, which bears interest based on LIBOR plus an applicable margin (as defined by the credit agreement), may be expanded to $600 million, subject to additional lender commitments, with approval of the

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administrative agent for the credit facility. At September 30, 2010, borrowings of approximately $222 million were outstanding under this facility.

(6) Our fixed-rate senior notes have a face value of approximately $4.4 billion as of September 30, 2010. We estimate the aggregate fair value of these notes as of September 30, 2010 to be approximately $4.9 billion. Our fixed-rate senior notes are traded among institutions, which trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near quarter end.

Credit Facilities

In October 2010, we renewed our 364-day committed hedged inventory credit facility, which matures in October 2011. The facility has a borrowing capacity of $500 million, which may be increased to $1.2 billion, subject to obtaining additional lender commitments. Borrowings under this facility will be used to finance (i) the purchase of hedged crude oil inventory for storage activities and (ii) foreign import activities.

Letters of Credit

In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. At September 30, 2010 and December 31, 2009, we had outstanding letters of credit of approximately $68 million and $76 million, respectively.

Note 6 Net Income Per Limited Partner Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2010 and 2009 (amounts in millions, except per unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Numerator for basic and diluted earnings per limited partner unit:				
Net income attributable to Plains	$ 81	$ 122	$ 363	$ 469
Less: General partner s incentive distribution paid (1)	(40)	(32)	(117)	(92)
Subtotal	41	90	246	377
Less: General partner 2% ownership (1)	(1)	(2)	(5)	(7)
Net income available to limited partners	40	88	241	370
Adjustment in accordance with application of the two-class method for MLPs (1)	(2)	(3)	(5)	(8)
	$ 38	$ 85	$ 236	$ 362

Net income available to limited partners in accordance with the application of the two-class method for MLPs								
Denominator:								
Basic weighted average number of limited partner units outstanding		136		130		136		128
Effect of dilutive securities:								
Weighted average LTIP units (2)		1		1		1		1
Diluted weighted average number of limited partner units outstanding		137		131		137		129
Basic net income per limited partner unit	$	0.28	$	0.65	$	1.73	$	2.84
Diluted net income per limited partner unit	$	0.28	$	0.65	$	1.72	$	2.82

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(1) We calculate net income available to limited partners based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). However, FASB guidance requires that the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter, be utilized in the earnings per unit calculation. After adjusting for this distribution, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the

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partnership agreement for earnings per unit calculation purposes. We reflect the impact of the difference in (i) the distribution utilized and (ii) the calculation of the excess 2% general partner interest as the Adjustment in accordance with application of the two-class method for MLPs.

(2) Our LTIP awards (described in Note 8) that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

Note 7 Partners Capital and Distributions

Sale of Noncontrolling Interest in a Subsidiary

PNG Initial Public Offering

On May 5, 2010, PNG completed its IPO of 13,478,000 common units representing limited partner interests at $21.50 per common unit. The number of units issued at closing included 1,758,000 common units issued pursuant to the full exercise of the underwriters over-allotment option. Net proceeds received by PNG from the sale of the 13,478,000 common units were approximately $268 million and were used to repay amounts outstanding under our credit facilities and for general partnership purposes. The common units offered represent approximately 23% of the outstanding equity of PNG. We own the remaining 77% equity interest in PNG and control the entity, and therefore, continue to consolidate the financial results.

Prior to the PNG IPO, we owned 100% of PNGS natural gas storage business, the predecessor of PNG, and related operating entities. Immediately prior to the closing of the IPO, we contributed 100% of the equity interests in PNGS and its subsidiaries to PNG in exchange for approximately 18.1 million common units, approximately 13.9 million Series A subordinated units, 11.5 million Series B subordinated units and a 2% general partner interest and incentive distribution rights. In conjunction with the offering, we recorded non-controlling interest of $167 million associated with the book value of PNG sold to the public. We also recorded an increase to our partners capital of approximately $101 million associated with the net increase from our share of the proceeds received in the offering partially offset by the dilution of our interest in PNG resulting from the IPO.

PAA Modification of Holdings in PNG Subordinated Units

On August 16, 2010, the Amended and Restated Agreement of Limited Partnership of PNG was amended and restated (the Second Amended and Restated Agreement) to reduce the number of series A subordinated units by 2 million and increase the number of series B subordinated units by an equivalent amount. The Second Amended and Restated Agreement also increased the number of potential conversion tranches on Series B subordinated units from three to five. In addition, the terms of the Series B subordinated units were modified to extend the conversion period by raising the operating and financial performance benchmarks of approximately one-third of the Series B subordinated units outstanding prior to this modification. This amendment was intended to increase the distribution coverage and organic growth profile of PNG s common and Series A subordinated units and improve PNG s posture with respect to potential acquisitions. We accounted for this transaction as an exchange between entities under common control and accordingly, we reclassified the book value of the 2.0 million Series A subordinated units at the time of the modification to Series B subordinated units.

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The following table sets forth the changes made to our holdings in the limited partner units of PNG from May 5, 2010 through September 30, 2010 (units in millions):

	Prior to Modification	Modification (in millions)	Post Modification
PNG Units Owned by PAA:			
Common Units	18.1		18.1
Series A Subordinated Units	13.9	(2.0)	11.9
Common & Series A Subordinated Unit Subtotal	32.0	(2.0)	30.0
Series B Subordinated Units (Performance Thresholds):			
Tranche 1 ($1.44 / 29.6 Bcf)	4.6	(2.0)	2.6
Tranche 2 ($1.53 / 35.6 Bcf)	3.8	(1.0)	2.8
Tranche 3 ($1.63 / 41.6 Bcf)	3.1	(1.0)	2.1
Tranche 4 ($1.71 / 48.0 Bcf)		3.0	3.0
Tranche 5 ($1.80 / 48.0 Bcf)		3.0	3.0
Series B Subordinated Unit Subtotal	11.5	2.0	13.5
Total PNG Units Owned by PAA(1)	43.5		43.5

(1) See PNG Transaction Grants in Note 8.

Series A and Series B Subordinated Units. The Series A subordinated units are not entitled to receive any distributions until the common units have received the minimum quarterly distribution ($1.35 on an annualized basis) plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. The Series A subordinated units will convert to common units once certain earnings and distribution targets are met for three consecutive, non-overlapping four-quarter periods. The Series B subordinated units are not entitled to participate in quarterly distributions until they convert into Series A subordinated units. The Series B subordinated units will convert into Series A subordinated units upon satisfaction of the following operational and financial conditions:

- 2,600,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 29.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.36 per unit (representing an annualized distribution of $1.44 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (c) PNG makes a quarterly distribution of available cash of at least $0.36 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2.0% interest and the related distributions on the incentive distribution rights;

- 2,833,333 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 35.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.3825 per unit (representing an annualized distribution of $1.53 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior bullet, and (c) PNG makes a quarterly distribution of available cash of at least $0.3825 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2.0% interest and the related distributions on the incentive distribution rights;

- 2,066,667 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 41.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4075 per unit (representing an annualized distribution of $1.63 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior two bullets, and (c) PNG makes a quarterly distribution of available cash of at least $0.4075 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2.0% interest and the related distributions on the incentive distribution rights; and

- 3,000,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 48.0 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4275 per unit (representing an annualized distribution of $1.71 per unit) on the weighted

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average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior three bullets, and (c) PNG makes a quarterly distribution of available cash of at least $0.4275 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2.0% interest and the related distributions on the incentive distribution rights; and

- 3,000,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 48.0 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.45 per unit (representing an annualized distribution of $1.80 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior four bullets, and (c) PNG makes a quarterly distribution of available cash of at least $0.45 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2.0% interest and the related distributions on the incentive distribution rights.

PNG s general partner will determine whether the in-service operational tests set forth above have been satisfied. To the extent that the operational tests described above are satisfied prior to or during the two-quarter period applicable to the financial tests described above, the holder of the Series B subordinated units subject to conversion will be entitled to receive the quarterly distribution payable with respect to the second quarter of such two-quarter period. In all other circumstances, where the operational tests are satisfied following the two-quarter period applicable to the financial tests, the holder of the Series B subordinated units subject to conversion will be entitled to receive any distribution payable following the satisfaction of such operational tests.

Any Series B subordinated units that remain outstanding as of December 31, 2018 will automatically be cancelled.

Following conversion of any Series B subordinated units into Series A subordinated units, such converted Series B subordinated units will further convert into common units (together with any other outstanding Series A subordinated units) to the extent that the tests for conversion of the Series A subordinated units are satisfied. In determining whether such conversion tests have been satisfied, the Series B subordinated units that have converted into Series A subordinated units will be treated as Series A subordinated units from and after the date of their conversion into Series A subordinated units.

If at the time the above operational and financial tests are satisfied, the subordination period has already ended and all outstanding Series A subordinated units have converted into common units, the Series B subordinated units will instead convert directly into common units on a one-for-one basis and participate in the quarterly distribution payable to common units.

Noncontrolling Interests Rollforward

The following table reflects the changes in the noncontrolling interests in partners capital (in millions):

	For the Nine Months Ended September 30,			
	2010		2009	
Beginning balance	$	63	$	
Sale of noncontrolling interests in subsidiaries		167		63
Net income attributable to noncontrolling interests		5		1
Distributions to noncontrolling interests		(5)		
Other		2		
Ending Balance	$	232	$	64

LTIP Vesting

In May 2010, in connection with the settlement of vested LTIP awards, we issued 283,187 common units at a price of $56.89, for a fair value of approximately $16 million.

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PAA Distributions

The following table details the distributions pertaining to 2010, net of reductions to the general partner s incentive distributions (in millions, except per unit amounts):

Date Declared	Date Paid or To Be Paid	Common Units	Distributions Paid General Partner Incentive	Distributions Paid General Partner 2%	Total	Distributions per limited partner unit
October 12, 2010	November 12, 2010 (1)	$ 129	$ 42	$ 3	$ 174	$ 0.9500
July 13, 2010	August 13, 2010	$ 129	$ 40	$ 3	$ 172	$ 0.9425
April 13, 2010	May 14, 2010	$ 127	$ 39	$ 3	$ 169	$ 0.9350
January 20, 2010	February 12, 2010	$ 126	$ 37	$ 3	$ 166	$ 0.9275

(1) Payable to unitholders of record on November 2, 2010, for the period July 1, 2010 through September 30, 2010.

Upon closing of the Pacific acquisition in November 2006, the Rainbow acquisition in May 2008 and the PNGS acquisition in September 2009, our general partner agreed to reduce the amounts due it as incentive distributions. The total reduction in incentive distributions related to these acquisitions is $83 million. Following the distribution in November 2010, the aggregate incentive distribution reductions remaining will be approximately $7 million. See Note 2 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K for further detail regarding our *General Partner Incentive Distributions*.

Note 8 Equity Compensation Plans

For discussion of our equity compensation awards, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K.

Adoption of PNG Plan

During April 2010, PNG s general partner adopted the PNG Plan. The majority of the awards granted under the PNG Plan will vest either upon (i) annualized PNG distribution levels of between $1.55 and $1.90 or (ii) upon the conversion of PNG s Series A or Series B subordinated units. The PNG Plan limits the number of PNG common units that may be delivered pursuant to awards under the plan to 3,000,000.

Class B Units of PNG s General Partner

During July 2010, the Board of Directors of PNG s general partner authorized the issuance of 165,000 PNG Class B Units. Approximately 97,625 PNG Class B Units were awarded and the remaining units are reserved for future grants. The PNG Class B Units earn the right to participate in distributions (i.e. become earned) in 25% increments 180 days following annualized PNG distribution levels of $2.00, $2.30, $2.50 and $2.70. In addition, 50% of the applicable earned units vest immediately upon becoming earned units and the remaining 50% vest on the fifth anniversary of the date of grant. If PNG Class B Units become earned units after the fifth anniversary of the date of grant, 100% of such units will vest immediately upon becoming earned units. When earned, the PNG Class B Units participate in quarterly distributions paid to PNG s general partner to the extent such distributions exceed $2.5 million per quarter. Assuming all 165,000 PNG Class B Units were granted and earned, the maximum participation rate would be 6% of PNG s quarterly general partner distribution in excess of $2.5 million. As the PNG distribution levels required for vesting are not currently considered to be probable of occurring, no expense was recognized for the PNG Class B Units during the three months ended September 30, 2010.

PNG Transaction Grants

During September 2010, we entered into agreements with certain of our officers, pursuant to which these officers acquired an aggregate of 375,000 phantom common units, phantom Series A subordinated units, and phantom Series B subordinated units representing a portion of the limited partner interests of PNG issued to us in the IPO. The awards, referred to herein as PNG Transaction Grants, will vest upon the completion of the service period and certain performance conditions, including the conversion of PNG s Series A subordinated units into common units of PNG and the conversion of PNG s Series B subordinated units into Series A subordinated units of PNG. Upon vesting, these awards will be settled with outstanding common or Series A subordinated units of PNG currently owned by us, resulting in a dilution of our interest in PNG.

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Our equity compensation activity for awards denominated in PAA and PNG units is summarized in the following table (units in millions):

	PAA Units (1)			PNG Units (2) (3)		
	Units		Weighted Average Grant Date Fair Value per Unit	Units		Weighted Average Grant Date Fair Value per Unit
Outstanding, December 31, 2009	3.9	$	36.40		$	
Granted	1.6	$	42.45	1.1	$	20.71
Vested	(0.7)	$	34.58		$	
Cancelled or forfeited	(0.4)	$	35.66		$	
Outstanding, September 30, 2010	4.4	$	38.93	1.1	$	20.71

(1) Amounts do not include PAA Class B units.

(2) Amounts do not include PNG Class B units.

(3) Amounts include PNG Transaction Grants.

The table below summarizes the expense recognized and unit or cash settled vestings related to all of our equity compensation plans (in millions):

	Three Months Ended September 30,				Nine Months Ended September 30,			
		2010		2009		2010		2009
Equity compensation expense	$	18	$	16	$	50	$	47
Unit settled vestings (PAA units only)	$	1	$		$	26	$	19
Cash settled vestings	$	1	$	1	$	11	$	7
DER cash payments	$	1	$	1	$	3	$	3

Note 9 Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. Our policy is to use derivative instruments only for risk management purposes. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange rate risk. Our commodity risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate and foreign currency risk management policies and procedures are designed to monitor our positions and ensure that those positions are consistent with our objectives and approved strategies. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged, and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items.

Commodity Price Risk Hedging

Our core business activities contain certain commodity price-related risks that we manage in various ways, including the use of derivative instruments. Our policy is (i) to purchase only product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect the segment profit we earn, and (iii) not to acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes. Although we seek to maintain positions that are substantially balanced, we purchase crude oil, refined products and LPG from thousands of locations and may experience net unbalanced positions as a result of production, transportation and delivery variances, as well as logistical issues associated with inclement weather conditions and other uncontrollable events. In connection with our efforts to maintain a balanced position, specifically authorized personnel can purchase or sell an aggregate limit of up to 810,000 barrels of crude oil, refined products and LPG relative to the volumes originally scheduled for such month, based on interim information. The purpose of these purchases and sales is to manage risk as opposed to establishing a risk position. When unscheduled physical inventory builds or draws do occur, they are monitored continuously and managed to a balanced position over a reasonable period of time.

The material commodity related risks inherent in our business activities can be summarized into the following general categories:

Commodity Purchases and Sales In the normal course of our supply and logistics operations, we purchase and sell crude oil, LPG, and refined products. We use derivatives to manage the associated risks and to optimize profits. As of September 30, 2010, net derivative positions related to these activities included:

- An approximate 207,800 barrels per day net long position (total of 6.2 million barrels) associated with our crude oil activities, which was unwound ratably during October 2010 to match monthly average pricing.

- An approximate 32,400 barrels per day (total of 15.5 million barrels) net short spread position, which hedges a portion of our anticipated crude oil lease gathering purchases through January 2012. These derivatives protect our margin on future floating-price crude oil purchase commitments. These derivatives in the aggregate do not result in exposure to outright price movements.

- A net short spread position averaging approximately 16,000 barrels per day (total of 6.7 million barrels) of calendar spread call options for the period November 2010 through December 2011. These derivatives in the aggregate do not result in exposure to outright price movements.

- Approximately 6,000 barrels per day on average (total of 5.1 million barrels) of WTS/WTI crude oil basis swaps through January 2013, which hedge anticipated sales of crude oil (WTI).

Storage Capacity Utilization We own approximately 63 million barrels of crude oil, LPG and refined products storage capacity that is not used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk if the market structure is backwardated. As of September 30, 2010, we used derivatives to manage the risk of not utilizing approximately 2.5 million barrels per month of storage capacity through 2012. These positions are a combination of calendar spread options and NYMEX futures contracts. These positions involve no outright price exposure, but instead represent potential offsetting purchases and sales between time periods (first month versus second month for example).

Inventory Storage At times, we elect to purchase and store crude oil, LPG and refined products inventory in conjunction with our supply and logistics activities. These activities primarily relate to the seasonal storage of LPG inventories and contango market storage activities. When we purchase and store barrels, we enter into physical sales contracts or use derivatives to mitigate price risk

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associated with the inventory. As of September 30, 2010, we had derivatives totaling approximately 17.2 million barrels hedging our inventory.

We also purchase foreign cargoes of crude oil and may enter into derivatives to mitigate various price risks associated with the purchase and ultimate sale of foreign crude inventory. As of September 30, 2010, we had approximately 2.1 million barrels of crude oil derivatives hedging the anticipated sale of foreign crude inventory.

Pipeline Loss Allowance Oil As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement, and other losses in transit. We utilize derivative instruments to hedge a portion of the anticipated sales of the allowance oil that is to be collected under our tariffs. As of September 30, 2010, we had PLA hedges consisting of (i) a net short position consisting of crude oil futures and swaps for an average of approximately 2,100 barrels per day (total of 1.7 million barrels) through December 2012, (ii) a long put option position of approximately 0.3 million barrels through December 2012 and (iii) a long call option position of approximately 1.1 million barrels through December 2011.

Natural Gas Purchases and Sales Our gas storage facilities require minimum levels of natural gas (base gas) to operate. For our natural gas storage facilities that are under construction, we anticipate purchasing base gas in future periods as construction is completed. We use derivatives to hedge such anticipated purchases of natural gas. As of September 30, 2010, we have a long position of approximately 1 Bcf consisting of natural gas futures contracts through August 2011 and natural gas call options for approximately 1 Bcf through August 2011. Additionally, we use derivatives to hedge anticipated sales of operational gas when that gas is no longer needed for cavern development purposes. As of September 30, 2010, we have a short futures position of approximately 1 Bcf consisting of NYMEX futures.

The derivative instruments we use to manage our commodity price risk consist primarily of futures, options and swaps traded on the NYMEX and ICE and in over-the-counter transactions. Over-the-counter transactions include commodity swap and option contracts. All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into AOCI and recognized in revenues or purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the NPNS exclusion and thus are not subject to the accounting treatment for derivative instruments and hedging activities as set forth in FASB guidance. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the NPNS scope exception are recorded on the balance sheet as assets or liabilities at their fair value, with changes in fair value recorded net in revenues.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and, in certain cases, outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of September 30, 2010, AOCI includes deferred losses of $8 million that relate to terminated interest rate swaps and treasury locks that were designated for hedge accounting. These terminated interest rate derivatives were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the hedged debt instruments.

As of September 30, 2010, we had four outstanding interest rate swaps. For the interest rate swaps, we receive fixed interest payments and pay floating-rate interest payments based on three-month LIBOR plus an average spread of 2.42% on a semi-annual basis. The swaps have an aggregate notional amount of $300 million with fixed rates of 4.25%. Two of the swaps terminate in 2011 and two of the swaps terminate in 2012.

During October 2010, we entered into three forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted debt issuances through 2013. The following table summarizes the terms of our forward starting interest rate swaps (notional amounts in millions):

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Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated debt offering	1 forward starting swap (30-year)	$ 50	12/15/2013	3.87%	Cash flow hedge
Anticipated debt offering	2 forward starting swaps (10-year)	$ 50	10/15/2012	3.30%	Cash flow hedge

Currency Exchange Rate Risk Hedging

We use foreign currency derivatives to hedge foreign currency risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. As of September 30, 2010, AOCI includes net deferred gains of $16 million that relate to open and settled forward exchange contracts that were designated for hedge accounting. These forward exchange contracts hedge the cash flow variability associated with CAD-denominated interest payments on a CAD-denominated intercompany note as a result of changes in the foreign exchange rate.

As of September 30, 2010, our outstanding foreign currency derivatives also include derivatives used to hedge CAD-denominated crude oil purchases and sales. We may from time to time hedge the commodity price risk associated with a CAD-denominated commodity transaction with a USD-denominated commodity derivative. In conjunction with entering into the commodity derivative, we may enter into a foreign currency derivative to hedge the resulting foreign currency risk. These foreign currency derivatives are generally short-term in nature and are not designated for hedge accounting.

At September 30, 2010, our open foreign exchange derivatives included forward exchange contracts that exchange CAD for USD on a net basis as follows (in millions):

	CAD	USD	Average Exchange Rate
2010	$ 11	$ 10	CAD $1.15 to USD $1.00
2011	$ 15	$ 15	CAD $1.01 to USD $1.00
2012	$ 15	$ 15	CAD $1.01 to USD $1.00
2013	$ 9	$ 9	CAD $1.00 to USD $1.00

These financial instruments are placed with large, highly rated financial institutions.

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price-risk hedging activities. All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to AOCI and recognized in earnings in the periods during which the underlying physical transactions impact earnings. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

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A summary of the impact of our derivative activities recognized in earnings for the three and nine months ended September 30, 2010 and 2009 is as follows (in millions):

Three months ended September 30, 2010 and 2009:

	Three Months Ended September 30, 2010			Three Months Ended September 30, 2009		
Location of gain/(loss)	**Derivatives in Cash Flow Hedging Relationships (1)**	**Derivatives Not Designated as a Hedge (3)**	**Total**	**Derivatives in Cash Flow Hedging Relationships (1)(2)**	**Derivatives Not Designated as a Hedge (3)**	**Total**
Commodity Derivatives						
Supply and Logistics segment revenues	$ 7	$ (32)	$ (25)	$ (158)	$ 11	$ (147)
Transportation segment revenues	1		1	1		1
Purchases and related costs	11	3	14	60	4	64
Interest Rate Derivatives						
Interest expense		1	1		1	1
Foreign Exchange Derivatives						
Supply and Logistics segment revenues		3	3		4	4
Purchases and related costs					2	2
Other income, net		(1)	(1)		(1)	(1)
Total Gain/(Loss) on Derivatives Recognized in Income	**$ 19**	**$ (26)**	**$ (7)**	**$ (97)**	**$ 21**	**$ (76)**

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Nine months ended September 30, 2010 and 2009:

Location of gain/(loss)	Nine Months Ended September 30, 2010 Derivatives in Cash Flow Hedging Relationships (1)	Derivatives Not Designated as a Hedge (3)	Total	Nine Months Ended September 30, 2009 Derivatives in Cash Flow Hedging Relationships (1)(2)	Derivatives Not Designated as a Hedge (3)	Total
Commodity Derivatives						
Supply and Logistics segment revenues	$ (20)	$ 23	$ 3	$ (24)	$ 17	$ (7)
Transportation segment revenues	2		2	4		4
Facilities segment revenues	(1)	1				
Purchases and related costs	9	(10)	(1)	29	119	148
Interest Rate Derivatives						
Other income, net					(1)	(1)
Interest expense	(1)	3	2	(1)	1	
Foreign Exchange Derivatives						
Supply and Logistics segment revenues					9	9
Purchases and related costs		2	2		(1)	(1)
Other income, net		(1)	(1)	5	(3)	2
Total Gain/(Loss) on Derivatives Recognized in Income	**$ (11)**	**$ 18**	**$ 7**	**$ 13**	**$ 141**	**$ 154**

(1) Amounts represent derivative gains and losses that were reclassified from AOCI to earnings during the period to coincide with the earnings impact of the respective hedged transaction.

(2) Amounts include gains of approximately $2 million and losses of approximately $6 million for the three and nine months ended September 30, 2009, respectively, that represent the ineffective portion of the fair value of our unrealized cash flow hedges. These amounts relate to commodity derivatives and are recognized in Supply and Logistics segment revenues during such periods.

(3) Includes realized and unrealized gains or losses for derivatives not designated for hedge accounting during the period.

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The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of September 30, 2010 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives designated as hedging instruments:						
Commodity derivatives	Other current assets	$	56	Other current assets	$	(38)
	Other long-term assets		18	Other long-term assets		(1)
				Other current liabilities		(3)
Foreign exchange derivatives	Other long-term assets		1			
Total derivatives designated as hedging instruments		$	75		$	(42)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	16	Other current assets	$	(64)
	Other long-term assets		8	Other long-term assets		(2)
	Other current liabilities		4	Other current liabilities		(11)
Interest rate derivatives	Other current assets		4			
	Other long-term assets		2			
Total derivatives not designated as hedging instruments		$	34		$	(77)
Total derivatives		$	109		$	(119)

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2009 (in millions):

	Asset Derivatives			Liability Derivatives		
	Balance Sheet Location		Fair Value	Balance Sheet Location		Fair Value
Derivatives designated as hedging instruments:						
Commodity derivatives	Other current assets	$	153	Other current liabilities	$	(140)
	Other long-term assets		34	Other long-term liabilities		(1)
Foreign exchange derivatives	Other long-term assets		2	Other long-term liabilities		
Total derivatives designated as hedging instruments		$	189		$	(141)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	34	Other current liabilities	$	(91)
	Other long-term assets		41	Other long-term liabilities		(34)
Interest rate derivatives	Other current assets		1	Other current liabilities		
	Other long-term assets		1	Other long-term liabilities		

Foreign exchange derivatives	Other current assets		2	Other current liabilities		(3)
Total derivatives not designated as hedging instruments		$	79		$	(128)
Total derivatives		$	268		$	(269)

As of September 30, 2010, there was a net gain of $23 million deferred in AOCI. The total amount of deferred net gain recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the

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underlying hedged commodity transaction, (ii) interest expense accruals associated with underlying debt instruments or (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD-denominated intercompany balances. Of the total net gain deferred in AOCI at September 30, 2010, we expect to reclassify a net gain of approximately $2 million to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 98% is expected to be reclassified to earnings prior to 2013 with the remaining deferred gain being reclassified to earnings through 2019. These amounts are predominately based on market prices at the current period end, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the nine months ended September 30, 2009, we discontinued a cash flow hedge as a result of the hedged transaction becoming no longer probable of occurring and reclassified a deferred gain of approximately $6 million from AOCI to other income. During the three months ended September 30, 2010 and 2009 and the nine months ended September 30, 2010, all of our hedged transactions were probable of occurring.

The net deferred gain/(loss) recognized in AOCI for derivatives during the three and nine months ended September 30, 2010 and September 30, 2009 are as follows (in millions):

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Commodity derivatives	$ (19)	$ 4	$ (5)	$ (79)
Foreign exchange derivatives	(1)	(5)	(2)	(7)
Interest rate derivatives		(2)	1	(2)
Total	$ (20)	$ (3)	$ (6)	$ (88)

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting agreement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of September 30, 2010, we had a net broker receivable of approximately $49 million (consisting of initial margin of $69 million reduced by $20 million of variation margin that had been returned to us). As of December 31, 2009, we had a net broker receivable of approximately $53 million (consisting of initial margin of $71 million reduced by $18 million of variation margin that had been returned to us). At September 30, 2010 and December 31, 2009, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2010. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which does affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of September 30, 2010 (in millions)				Fair Value as of December 31, 2009 (in millions)			
Recurring Fair Value Measures(1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ (3)	$	$ (14)	$ (17)	$ 27	$	$ (31)	$ (4)
Interest rate derivatives			6	6			2	2
Foreign currency derivatives			1	1			1	1
Total	$ (3)	$	$ (7)	$ (10)	$ 27	$	$ (28)	$ (1)

(1) Derivative assets and liabilities are presented above on a net basis but do not include related cash collateral amounts.

The determination of the fair values above includes not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives, interest-rate derivatives and foreign currency derivatives includes adjustments for credit risk. We measure credit risk by deriving a probability of default from market-observed credit default swap spreads as of the measurement date. The probability of default is applied to the net credit exposure of each of our

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counterparties and includes a recovery rate adjustment. The recovery rate is an estimate of what would ultimately be recovered through a bankruptcy proceeding in the event of default. There were no changes to any of our valuation techniques during the period.

Level 1

Included within level 1 of the fair value hierarchy are exchange-traded commodity derivatives such as futures, options and swaps. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets and is therefore classified within level 1 of the fair value hierarchy.

Level 2

There was no activity during the quarter within level 2 of the fair value hierarchy.

Level 3

Included within level 3 of the fair value hierarchy are the following derivatives:

- Commodity Derivatives: Level 3 commodity derivatives include over-the-counter commodity derivatives such as forwards, swaps and options and certain physical commodity contracts. The fair value of our level 3 commodity derivatives is based on either an indicative broker or dealer price quotation or a valuation model. Our valuation models utilize inputs such as price, volatility and correlation but do not involve significant management judgments.

- Interest Rate Derivatives: Level 3 interest rate derivatives include interest rate swaps. The fair value of our interest rate derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward LIBOR curves and forward treasury yields that are obtained from pricing services.

- Foreign Currency Derivatives: Level 3 foreign currency derivatives include foreign currency swaps, forward exchange contracts and options. The fair value of our foreign currency derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward CAD/USD forward exchange rates that are obtained from pricing services.

The majority of our level 3 derivatives are classified as such because the broker or dealer price quotations used to measure fair value and the pricing services used to corroborate the quotations are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these level 3 derivatives is not based upon significant management assumptions or subjective inputs.

Rollforward of Level 3 Net Liability

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives classified as level 3 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Beginning Balance	$ 8	$ (5)	$ (28)	$ 74
Unrealized gains/(losses):				
Included in earnings (1)	(16)	3	(2)	57
Included in other comprehensive income	3	(10)	3	(32)
Settlements and derivatives entered into during the period	(2)	(1)	20	(112)
Ending Balance	$ (7)	$ (13)	$ (7)	$ (13)
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ (22)	$	$ (4)	$ (8)

(1) We reported unrealized gains and losses associated with level 3 commodity derivatives in our consolidated statements of operations as Supply and Logistics segment revenues. Gains and losses associated with interest rate derivatives are reported in our consolidated statements of operations as Interest expense. Gains and losses associated with foreign currency derivatives are reported in our consolidated statements of operations as either Supply and Logistics segment revenues, Purchases and related costs, or Other income, net.

We believe that a proper analysis of our level 3 gains or losses must incorporate the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and will therefore be offset by gains or losses on the underlying transactions.

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Note 10 Commitments and Contingencies

Litigation

United States Environmental Protection Agency v. Plains All American Pipeline, L.P. In September, the United States District Court for the Southern District of Texas entered an order approving a Consent Decree that represented our settlement agreement with the U.S. Environmental Protection Agency and the U.S. Department of Justice regarding a 2004 crude oil release that reached the Pecos River and a 2005 crude oil release that reached the Sabine River, as well as eight smaller releases. Pursuant to the Consent Decree, we paid $3.25 million in civil penalties, which we had fully reserved in our contingency accrual. Over the last several years PAA has proactively developed and implemented risk assessment, pipeline integrity and leak detection procedures that are incremental to those mandated by regulation. As a result of this effort and the ongoing process with EPA and DOJ, many of the operational requirements contained in the Consent Decree have already been incorporated into PAA s operating practices, and the anticipated costs of compliance have been incorporated into our planning.

SemCrude L.P., et al Debtors/Samson Resources Company (U.S. Bankruptcy Court Delaware). We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude, which commenced in July 2008. Statutory protections and our contractual rights of setoff covered substantially all of our pre-petition claims against SemCrude and such claims have now been resolved. In separate actions certain creditors of SemCrude, led by Samson Resources Company, have also filed state court actions alleging a producer s lien on crude oil sold to SemCrude and its affiliates, and the continuation of such lien when SemCrude and its affiliates subsequently sold the oil to purchasers such as us. On May 29, 2009, we filed a complaint for declaratory relief to resolve these claims. Fourteen state court actions have been consolidated in Bankruptcy Court. One action is in Federal Court in New Mexico. The aggregate amount subject to challenge is approximately $23 million. We intend to vigorously defend our contractual and statutory rights.

On November 15, 2006, we completed the Pacific merger. The following is a summary of the more significant matters that relate to Pacific, its assets or operations.

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ExxonMobil Corp. v. GATX Corp. (Superior Court of New Jersey Gloucester County). This Pacific legacy matter was filed by ExxonMobil in April 2003 and involves the allocation of responsibility for remediation of MTBE and other petroleum product contamination at the PAT facility at Paulsboro, New Jersey. We estimate that the maximum potential cost to effectively remediate ranges from $3.5 million to up to $10 million. Both ExxonMobil and GATX were prior owners of the terminal. We contend that ExxonMobil and/or GATX are primarily responsible for the majority of the remediation costs. We are in dispute with Kinder Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific s purchase of the facility. We are vigorously defending against any claim that PAT is directly or indirectly liable for damages or costs associated with the MTBE contamination.

NJDEP v. ExxonMobil Corp. et al. In a matter related to ExxonMobil v. GATX, in June 2007, the NJDEP brought suit against GATX, Exxon and PAT to recover natural resources damages associated with, and to require remediation of, the contamination. ExxonMobil and GATX have filed third-party demands against PAT, seeking indemnity and contribution. The natural resources damages have been settled and set at $1.1 million payable to the State of New Jersey; however, PAT s allocated share of this liability is being disputed by PAT with GATX. Court approval of the settlement is pending.

EPA v. RMPS. In February 2009, we received a request for information from EPA regarding aspects of the fuel handling activities of RMPS, a subsidiary acquired in the Pacific merger, at two truck terminals in Colorado. These activities, performed at the request of customers, included the mixture of certain blendstocks with gasoline. We provided the information requested, and cooperated in EPA s investigation of such activities. In January 2010, we received a notice of violations from EPA, alleging failure of RMPS to comply with provisions of the CAA related to registration, sampling, recording and reporting in connection with such activities. EPA further alleges that the violations occurred on an ongoing basis from October 2006 through February 2009. EPA has referred the matter to DOJ. We continue to engage in discussion with EPA, and to emphasize those factors that should mitigate the severity of any penalties imposed. In December 2009, RMPS self-reported late filing of certain reports required under Clean Air Act Diesel Fuel Regulations. All reports have now been filed.

Other Pacific-Legacy Matters. Although we believe that our operations are presently in material compliance with applicable requirements, it is possible that EPA or other governmental entities may seek to impose fines, penalties or performance obligations on us, or on a portion of our operations, as a result of any past noncompliance that may have occurred.

General. We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental

Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline and storage operations. These releases can result from unpredictable man-made or natural forces and may reach navigable waters or other sensitive environments. For example, when the area around Lubbock, Texas received an unusually heavy rainfall in early July 2010, a branch of the Brazos River became swollen beyond flood stage. The unusually erosive power of the water undercut existing river banks and caused them to collapse. This phenomenon occurred at a river crossing for one of our 4-inch gathering lines. The combined force of the shifting mass of earth and rushing water severed the pipe, apparently allowing the release of crude oil into the river. We estimate that a maximum of 165 barrels may have been released. We also may discover environmental impacts from past releases that were previously unidentified. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

As we expand our pipeline assets through acquisitions, we typically improve on (reduce) the releases from such assets (in terms of frequency or volume) as we implement our procedures, remove selected assets from service and spend capital to upgrade the assets. However, the inclusion of additional miles of pipe in our operations may result in an increase in the absolute number of releases company-wide compared to prior periods.

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At September 30, 2010, our reserve for environmental liabilities totaled approximately $66 million, of which approximately $11 million is classified as short-term and $55 million is classified as long-term. At September 30, 2010, we have recorded receivables totaling approximately $4 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, although we believe that the reserve is adequate, costs incurred may be in excess of the reserve and may potentially have a material adverse effect on our financial condition, results of operations, or cash flows.

Insurance

A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and certain assets. The insurance policies are subject to deductibles or self-insured retentions that we consider reasonable. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. As a result, we may elect to self-insure or utilize higher deductibles in certain insurance programs. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Note 11 Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply & Logistics. The following table reflects certain financial data for each segment for the periods indicated (in millions):

	Transportation	Facilities	Supply & Logistics	Total
Three Months Ended September 30, 2010				
Revenues:				
External Customers	$ 144	$ 91	$ 6,179	$ 6,414
Intersegment (1)	121	36		157
Total revenues of reportable segments	$ 265	$ 127	$ 6,179	$ 6,571
Equity earnings in unconsolidated entities	$ 1	$	$	$ 1

Segment profit (2) (3)	$	137	$	73	$	2	$	212
Maintenance capital	$	21	$	5	$	3	$	29
Three Months Ended September 30, 2009								
Revenues:								
External Customers	$	147	$	65	$	4,645	$	4,857
Intersegment (1)		103		32				135
Total revenues of reportable segments	$	250	$	97	$	4,645	$	4,992
Equity earnings in unconsolidated entities	$	2	$	3	$		$	5
Segment profit (2) (3)	$	129	$	57	$	44	$	230
Maintenance capital	$	9	$	2	$	1	$	12

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	Transportation		Facilities		Supply & Logistics		Total	
Nine Months Ended September 30, 2010								
Revenues:								
External Customers	$	421	$	249	$	17,992	$	18,662
Intersegment (1)		353		113		1		467
Total revenues of reportable segments	$	774	$	362	$	17,993	$	19,129
Equity earnings in unconsolidated entities	$	3	$		$		$	3
Segment profit (2) (3)	$	394	$	202	$	152	$	748
Maintenance capital	$	43	$	13	$	6	$	62
Nine Months Ended September 30, 2009								
Revenues:								
External Customers	$	401	$	165	$	11,876	$	12,442
Intersegment (1)		313		94		1		408
Total revenues of reportable segments	$	714	$	259	$	11,877	$	12,850
Equity earnings in unconsolidated entities	$	5	$	8	$		$	13
Segment profit (2) (3)	$	355	$	155	$	282	$	792
Maintenance capital	$	40	$	11	$	5	$	56

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(1) Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. For further discussion, see Analysis of Operating Segments under Item 7 of our 2009 Annual Report on Form 10-K.

(2) Supply & logistics segment profit includes interest expense on contango inventory purchases of $5 million and $4 million for the three months ended September 30, 2010 and 2009, respectively, and $13 million and $8 million for the nine months ended September 30, 2010 and 2009, respectively.

(3) The following table reconciles segment profit to net income attributable to Plains (in millions):

	For the Three Months Ended September 30,				For the Nine Months Ended September 30,			
	2010		2009		2010		2009	
Segment profit	$	212	$	230	$	748	$	792
Depreciation and amortization		(61)		(59)		(192)		(173)
Interest expense		(64)		(59)		(183)		(165)
Other income/(expense), net		(7)		12		(9)		17
Income tax benefit/(expense)		4		(2)		4		(1)
Net income		84		122		368		470
Less: Net income attributable to noncontrolling interests		(3)				(5)		(1)
Net income attributable to Plains	$	81	$	122	$	363	$	469

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Note 12 Supplemental Condensed Consolidating Financial Information

For purposes of this Note 12, Plains is referred to as Parent. See Note 13 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K for further detail regarding subsidiaries classified as Guarantor Subsidiaries and subsidiaries classified as Non-Guarantor Subsidiaries. There have been no material changes in the entities that constitute our guarantor and non-guarantor subsidiaries since December 31, 2009.

The following supplemental condensed consolidating financial information reflects the Parent s separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and the Parent s consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent s investments in its subsidiaries and the Guarantor Subsidiaries investments in their subsidiaries are accounted for under the equity method of accounting (in millions):

Condensed Consolidating Balance Sheet

	As of September 30, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,847	$ 3,966	$ 272	$ (3,314)	$ 3,771
Property and equipment, net	1	4,760	1,771		6,532
Other assets, net	6,188	3,933	368	(8,055)	2,434
Total assets	$ 9,036	$ 12,659	$ 2,411	$ (11,369)	$ 12,737
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 326	$ 6,267	$ 288	$ (3,314)	$ 3,567
Long-term debt	4,367	5	226	(5)	4,593
Other long-term liabilities		231	3		234
Total liabilities	4,693	6,503	517	(3,319)	8,394
Partners capital excluding noncontrolling interests	4,111	6,094	1,894	(7,988)	4,111
Noncontrolling interests	232	62		(62)	232
Total partners capital	4,343	6,156	1,894	(8,050)	4,343
Total liabilities and partners capital	$ 9,036	$ 12,659	$ 2,411	$ (11,369)	$ 12,737

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	As of December 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 3,428	$ 3,831	$ 209	$ (3,810)	$ 3,658
Property and equipment, net		4,606	1,734		6,340
Other assets, net	5,324	3,994	367	(7,325)	2,360
Total assets	$ 8,752	$ 12,431	$ 2,310	$ (11,135)	$ 12,358
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 456	$ 6,849	$ 287	$ (3,810)	$ 3,782
Long-term debt	4,137	15	450	(460)	4,142
Other long-term liabilities		271	4		275
Total liabilities	4,593	7,135	741	(4,270)	8,199
Partners capital excluding noncontrolling interest	4,096	5,233	1,569	(6,802)	4,096
Noncontrolling interest	63	63		(63)	63
Total partners capital	4,159	5,296	1,569	(6,865)	4,159
Total liabilities and partners capital	$ 8,752	$ 12,431	$ 2,310	$ (11,135)	$ 12,358

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Condensed Consolidating Statements of Operations

	Three Months Ended September 30, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 383	$ 60	$	$ 443
Field operating costs		(162)	(14)		(176)
General and administrative expenses		(50)	(6)		(56)
Depreciation and amortization	(1)	(49)	(11)		(61)
Operating income	(1)	122	29		150
Equity earnings in unconsolidated entities	155	28		(182)	1
Interest income/(expense)	(64)	1	(1)		(64)
Other income/(expense), net	(6)	(1)			(7)
Income tax expense		4			4
Net income	$ 84	$ 154	$ 28	$ (182)	$ 84
Less: Net income attributable to noncontrolling interests	(3)	(1)		1	(3)
Net income attributable to Plains	$ 81	$ 153	$ 28	$ (181)	$ 81

	Three Months Ended September 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 396	$ 44	$	$ 440
Field operating costs		(150)	(13)		(163)
General and administrative expenses		(48)	(4)		(52)
Depreciation and amortization	(1)	(49)	(9)		(59)
Operating income	(1)	149	18		166
Equity earnings in unconsolidated entities	184	19		(198)	5
Interest income/(expense)	(61)	3	(1)		(59)
Other income, net		12			12
Income tax expense		(2)			(2)
Net income	$ 122	$ 181	$ 17	$ (198)	$ 122

	Nine Months Ended September 30, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 1,264	$ 165	$	$ 1,429
Field operating costs		(468)	(42)		(510)
General and administrative expenses		(154)	(20)		(174)
Depreciation and amortization	(3)	(155)	(34)		(192)
Operating income	(3)	487	69		553
Equity earnings in unconsolidated entities	566	65		(628)	3
Interest income/(expense)	(189)	13	(7)		(183)
Other income/(expense), net	(6)	(3)			(9)
Income tax expense		4			4
Net income	$ 368	$ 566	$ 62	$ (628)	$ 368
Less: Net income attributable to noncontrolling interests	(5)	(1)		1	(5)
Net income attributable to Plains	$ 363	$ 565	$ 62	$ (627)	$ 363

	Nine Months Ended September 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 1,296	$ 110	$	$ 1,406
Field operating costs		(442)	(32)		(474)
General and administrative expenses		(144)	(9)		(153)
Depreciation and amortization	(3)	(148)	(22)		(173)
Operating income	(3)	562	47		606
Equity earnings in unconsolidated entities	642	51		(680)	13
Interest income/(expense)	(170)	6	(1)		(165)
Other income, net		17			17
Income tax expense		(1)			(1)
Net income	$ 469	$ 635	$ 46	$ (680)	$ 470
Less: Net income attributable to noncontrolling interest		(1)			(1)
Net income attributable to Plains	$ 469	$ 634	$ 46	$ (680)	$ 469

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(1) Net operating revenues are calculated as Total revenues less Purchases and related costs.

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Condensed Consolidating Statements of Cash Flows

	Nine Months Ended September 30, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 368	$ 566	$ 62	$ (628)	$ 368
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	3	155	34		192
Equity compensation charge		49	1		50
Gain on sale of linefill		(18)			(18)
Loss on early redemption of senior notes	6				6
Other	(565)	(63)		628	
Changes in assets and liabilities, net of acquisitions	337	(241)	(231)		(135)
Net cash provided by (used in) operating activities	149	448	(134)		463
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired	(20)	(177)			(197)
Additions to property, equipment and other		(250)	(73)		(323)
Cash received for sale of noncontrolling interest in a subsidiary	268				268
Net cash received for linefill		30	(10)		20
Proceeds from the sale of assets and other		5			5
Net cash used in investing activities	248	(392)	(83)		(227)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on Plains revolving credit facility	(111)	(170)			(281)
Net borrowings on PNG revolving credit facility			222		222
Net repayments on short-term letter of credit and hedged inventory facility		100			100
Net proceeds from the issuance of senior notes	400				400
Repayment of senior notes	(175)				(175)
Distributions paid to common unitholders and general partner	(507)				(507)
Distributions paid to noncontrolling interest			(5)		(5)
Other financing activities	(4)	3			(1)
Net cash provided by (used in) financing activities	(397)	(67)	217		(247)
Effect of translation adjustment on cash		(1)			(1)

Net increase/(decrease) in cash and cash equivalents		(12)			(12)
Cash and cash equivalents, beginning of period	1	19	5		25
Cash and cash equivalents, end of period	$ 1	$ 7	$ 5	$	$ 13

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	Nine Months Ended September 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 469	$ 635	$ 46	$ (680)	$ 470
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	3	148	22		173
Equity compensation charge		46	1		47
Other	(638)	(85)		680	(43)
Changes in assets and liabilities, net of acquisitions	(826)	535	(9)		(300)
Net cash provided by operating activities	(992)	1,279	60		347
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired		(117)			(117)
Additions to property, equipment and other		(301)	(53)		(354)
Investments in unconsolidated entities	(4)				(4)
Cash received for sale of noncontrolling interest in a subsidiary		26			26
Proceeds from the sale of assets and other		12			12
Net cash used in investing activities	(4)	(380)	(53)		(437)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on Plains revolving credit facility	(182)	(272)			(454)
Net borrowings on short-term letter of credit and hedged inventory facility		(180)			(180)
Repayment of PNGS debt		(446)			(446)
Net proceeds from the issuance of senior notes	1,346				1,346
Repayments of senior notes	(175)				(175)
Net proceeds from the issuance of common units	458				458
Distributions paid to common unitholders and general partner	(442)				(442)
Other financing activities	(9)				(9)
Net cash used in financing activities	996	(898)			98
Effect of translation adjustment on cash		(3)			(3)
Net increase/(decrease) in cash and cash equivalents		(2)	7		5
Cash and cash equivalents, beginning of period	2	9			11
Cash and cash equivalents, end of period	$ 2	$ 7	$ 7	$	$ 16

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Item 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2009 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the condensed consolidated financial statements and related notes that are contained in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Executive Summary

We provide transportation, storage, terminalling, supply and logistics services with respect to crude oil, refined products and LPG. We are also engaged in the development and operation of natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics.

Our discussion and analysis herein includes the following:

- Acquisitions and Internal Growth Projects
- Results of Operations
- Liquidity and Capital Resources
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates

- Forward-Looking Statements

Acquisitions and Internal Growth Projects

The following table summarizes our capital expenditures for acquisitions, internal growth projects, maintenance capital and investments in unconsolidated entities for the periods indicated (in millions):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Acquisition capital (1)	$ 166	$ 281
Internal growth projects	236	261
Maintenance capital	62	56
Other		4
Total	$ 464	$ 602

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(1) 2010 acquisition capital primarily includes the acquisition of (i) a 34% interest in White Cliffs Pipeline L.L.C. and (ii) an additional 11% interest in Capline pipeline. These acquisitions are reflected within our transportation segment.

Our internal growth projects primarily relate to the construction and expansion of pipeline systems, crude oil storage and terminal facilities and natural gas storage facilities. The following table summarizes our more notable projects in progress during 2010 and the forecasted expenditures for the remainder of the year (in millions):

Projects	2010
PAA Natural Gas Storage	$ 90
Cushing - Phases VII - XI	55
St. James - Phase III	25
Patoka Phase III	18
West Texas gathering lines	16
Edmonton land purchase	16
Wichita Falls tanks	11
Other projects (1)	149
	380
Maintenance capital	85 - 90
Total Projected Capital Expenditures (excluding acquisitions)	$ 465 - 470

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(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2009.

Results of Operations

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. In order to evaluate segment performance, management focuses on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital. See Note 15 to our Consolidated Financial Statements

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included in Part IV of our 2009 Annual Report on Form 10-K for further discussion on how we evaluate segment performance.

The following table reflects our segment profit, net income attributable to Plains and applicable earnings per limited partner unit for the three and nine months ended September 30, 2010 and 2009 (in millions, except per unit amounts):

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Three Months Favorable/ (Unfavorable) Variance $	Three Months Favorable/ (Unfavorable) Variance %	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Nine Months Favorable/ (Unfavorable) Variance $	Nine Months Favorable/ (Unfavorable) Variance %
Transportation segment profit	$ 137	$ 129	$ 8	6%	$ 394	$ 355	$ 39	11%
Facilities segment profit	73	57	16	28%	202	155	47	30%
Supply & Logistics segment profit	2	44	(42)	(95)%	152	282	(130)	(46)%
Total segment profit	212	230	(18)	(8)%	748	792	(44)	(6)%
Depreciation and amortization	(61)	(59)	(2)	(3)%	(192)	(173)	(19)	(11)%
Interest expense	(64)	(59)	(5)	(8)%	(183)	(165)	(18)	(11)%
Other income/(expense), net	(7)	12	(19)	(158)%	(9)	17	(26)	(153)%
Income tax benefit/(expense)	4	(2)	6	300%	4	(1)	5	500%
Net income	84	122	(38)	(31)%	368	470	(102)	(22)%
Less: Net income attributable to noncontrolling interests	(3)		(3)	N/A	(5)	(1)	(4)	(400)%
Net income attributable to Plains	$ 81	$ 122	$ (41)	(34)%	$ 363	$ 469	$ (106)	(23)%
Earnings per basic limited partner unit	$ 0.28	$ 0.65	$ (0.37)	(57)%	$ 1.73	$ 2.84	$ (1.11)	(39)%
Earnings per diluted limited partner unit	$ 0.28	$ 0.65	$ (0.37)	(57)%	$ 1.72	$ 2.82	$ (1.10)	(39)%
Basic weighted average units outstanding	136	130	6	5%	136	128	8	6%
Diluted weighted average units outstanding	137	131	6	5%	137	129	8	6%

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Analysis of Operating Segments

Transportation Segment

The following table sets forth the operating results from our transportation segment for the periods indicated:

Operating Results (1)	**Three Months Ended September 30,**		**Three Months Favorable/ (Unfavorable) Variance**		**Nine Months Ended September 30,**		**Nine Months Favorable/ (Unfavorable) Variance**	
(in millions, except per barrel amounts)	**2010**	**2009**	**$**	**%**	**2010**	**2009**	**$**	**%**
Revenues (1)								
Tariff activities	$ 240	$ 228	$ 12	5%	$ 697	$ 644	$ 53	8%
Trucking	25	22	3	14%	77	70	7	10%
Total transportation revenues	265	250	15	6%	774	714	60	8%
Costs and Expenses (1)								
Trucking costs	(17)	(15)	(2)	(13)%	(52)	(47)	(5)	(11)%
Field operating costs (excluding equity compensation expense)	(88)	(86)	(2)	(2)%	(258)	(249)	(9)	(4)%
Equity compensation expense - operations (2)	(3)	(2)	(1)	(50)%	(7)	(6)	(1)	(17)%
Segment G&A expenses (excluding equity compensation expense)	(15)	(14)	(1)	(7)%	(48)	(45)	(3)	(7)%
Equity compensation expense - general and administrative (2)	(6)	(6)		%	(18)	(17)	(1)	(6)%
Equity earnings in unconsolidated entities	1	2	(1)	(50)%	3	5	(2)	(40)%
Segment profit	$ 137	$ 129	$ 8	6%	$ 394	$ 355	$ 39	11%
Maintenance capital	$ 21	$ 9	$ (12)	(133)%	$ 43	$ 40	$ (3)	(8)%
Segment profit per barrel	$ 0.48	$ 0.48	$	%	$ 0.48	$ 0.44	$ 0.04	9%

Average Daily Volumes	**Three Months Ended September 30,**		**Three Months Favorable/ (Unfavorable) Variance**		**Nine Months Ended September 30,**		**Nine Months Favorable/ (Unfavorable) Variance**	
(in thousands of barrels per day) (3)	**2010**	**2009**	**Volumes**	**%**	**2010**	**2009**	**Volumes**	**%**
Tariff activities								
All American	37	43	(6)	(14)%	40	40		%
Basin	401	335	66	20%	376	389	(13)	(3)%
Capline	260	205	55	27%	222	205	17	8%
Line 63/Line 2000	108	141	(33)	(23)%	110	136	(26)	(19)%
Salt Lake City Area Systems	143	152	(9)	(6)%	136	132	4	3%
West Texas/New Mexico Area Systems	385	355	30	8%	379	375	4	1%
Manito	56	62	(6)	(10)%	59	62	(3)	(5)%
Rainbow	177	176	1	1%	189	184	5	3%
Rangeland	53	51	2	4%	51	54	(3)	(6)%
Refined products	110	100	10	10%	117	96	21	22%

Other	1,243	1,219	24	2%	1,210	1,207	3	%
Tariff activities total	2,973	2,839	134	5%	2,889	2,880	9	%
Trucking	99	80	19	24%	94	84	10	12%
Transportation segment total	3,072	2,919	153	5%	2,983	2,964	19	1%

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(1) Revenues and costs and expenses include intersegment amounts.

(2) Equity compensation expense related to our equity compensation plans. See Note 8 to our Condensed Consolidated Financial Statements for additional discussion of our equity compensation plans.

(3) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Transportation segment profit and segment profit per barrel were impacted by the following:

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As noted in the table above, our transportation segment revenues (less trucking costs) increased for the three and nine months ended September 30, 2010 compared to the three and nine months ended September 30, 2009, while volumes remained relatively consistent over these comparative periods. The significant variances between the comparative periods are discussed below:

- Tariff Rates   Revenues increased on some of our pipeline systems for the three and nine months ended September 30, 2010 compared to the three and nine months ended September 30, 2009 as a result of increased base tariff rates and indexing by the FERC.

- Foreign Currency Impact - Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, were translated at the prevailing average exchange rate for each month. During 2010, revenues from some of our Canadian pipeline systems were favorably impacted by the depreciation of the U.S. dollar relative to the Canadian dollar. The average Canadian dollar to U.S. dollar exchange rate for the three-month period ended September 30, 2010 was $1.04 CAD: $1.00 USD compared to an average of $1.10 CAD: $1.00 USD for the three-month period ended September 30, 2009. The average Canadian dollar to U.S. dollar exchange rate for the nine-month period ended September 30, 2010 was $1.04 CAD: $1.00 USD compared to an average of $1.17 CAD: $1.00 USD for the nine-month period ended September 30, 2009.

- Loss Allowance Revenue - As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The loss allowance revenue increased by approximately $2 million and $6 million for the three and nine months ended September 30, 2010 compared to the three and nine months ended September 30, 2009, respectively. The increase was primarily due to a higher average realized price per barrel during 2010 compared to 2009 (including the impact of gains and losses from derivative activities).

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (both excluding equity compensation charges) increased in the nine months ended September 30, 2010 over the nine months ended September 30, 2009 primarily due to the negative impact of foreign currency exchange rates as well as increases in most cost categories consistent with the overall growth of the segment.

Maintenance Capital. The increase in maintenance capital in the three and nine months ended September 30, 2010 over the three and nine months ended September 30, 2009 is primarily due to timing of various pipeline repair projects and API 653 repairs during each year.

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Facilities Segment

The following table sets forth the operating results from our facilities segment for the periods indicated:

Operating Results (in millions, except per barrel amounts)	Three Months Ended September 30, 2010	2009	Three Months Favorable/ (Unfavorable) Variance $	%	Nine Months Ended September 30, 2010	2009	Nine Months Favorable/ (Unfavorable) Variance $	%
Storage and terminalling revenues (1)	$ 127	$ 97	$ 30	31%	$ 362	$ 259	$ 103	40%
Storage related costs (natural gas related)	(5)	(1)	(4)	(400)%	(16)	(1)	(15)	(1,500)%
Field operating costs (excluding equity compensation expense)	(37)	(32)	(5)	(16)%	(106)	(85)	(21)	(25)%
Equity compensation expense - operations(2)				N/A	(1)	(1)		%
Segment G&A expenses (excluding equity compensation expense)	(9)	(7)	(2)	(29)%	(29)	(18)	(11)	(61)%
Equity compensation expense - general and administrative (2)	(3)	(3)		%	(8)	(7)	(1)	(14)%
Equity earnings in unconsolidated entities		3	(3)	(100)%		8	(8)	(100)%
Segment profit	$ 73	$ 57	$ 16	28%	$ 202	$ 155	$ 47	30%
Maintenance capital	$ 5	$ 2	$ (3)	(150)%	$ 13	$ 11	$ (2)	(18)%
Segment profit per barrel	$ 0.34	$ 0.31	$ 0.03	10%	$ 0.33	$ 0.29	$ 0.04	14%

Volumes (3)(4)(5)	Three Months Ended September 30, 2010	2009	Three Months Favorable/ (Unfavorable) Variance Volumes	%	Nine Months Ended September 30, 2010	2009	Nine Months Favorable/ (Unfavorable) Variance Volumes	%
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	62	56	6	11%	61	56	5	9%
Natural gas storage (average monthly capacity in billions of cubic feet)	50	27	23	85%	46	21	25	119%
LPG processing (average throughput in thousands of barrels per day)	17	17		%	14	16	(2)	(13)%
Facilities segment total (average monthly capacity in millions of barrels)	71	61	10	16%	69	60	9	15%

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(1) Includes intersegment amounts.

(2) Equity compensation expense related to our equity compensation plans. See Note 8 to our Condensed Consolidated Financial Statements for additional discussion of our equity compensation plans.

(3) Volumes associated with acquisitions represent total volumes for the number of months we actually owned the assets divided by the number of months in the period.

(4) Facilities total calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) LPG processing volumes multiplied by the number of days in the period and divided by the number of months in the period.

(5) In September 2009, we acquired the remaining 50% indirect interest in PNGS, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, natural gas storage volumes for January through August 2009 are netted to our 50% interest in PNGS. Beginning in September 2009, volumes represent our 100% interest in PNGS.

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Facilities segment profit and segment profit per barrel were impacted by the following:

As noted in the table above, our facilities segment revenues (less storage related costs) and volumes increased for the three and nine months ended September 30, 2010 over the three and nine months ended September 30, 2009. The significant variances in revenues and average monthly volumes between the comparative periods are discussed below:

- Acquisitions Revenues net of storage related costs and volumes for the three and nine months ended September 30, 2010 over the three and nine months ended September 30, 2009 were primarily impacted by the PNGS acquisition, which closed at the end of the third quarter of 2009. This acquisition and ongoing expansion activities at PNG contributed approximately $15 million and $49 million of additional net revenue and approximately 23 Bcf and 25 Bcf of additional natural gas storage capacity for the three and nine months ended September 30, 2010, respectively, compared to the corresponding periods during 2009. Revenues were also favorably impacted by the acquisition of a natural gas processing business, which closed during the second quarter of 2009. This acquisition contributed approximately $8 million in additional revenue for the nine months ended September 30, 2010.

- Expansion Projects Expansion projects that were completed in phases throughout 2009 also favorably impacted revenues and volumes during the comparative periods. These expansion projects, which were completed at some of our major terminal locations, increased our revenues by a combined $5 million and $11 million, respectively for the three and nine months ended September 30, 2010, compared to the same time periods of the prior year. Aggregate volumes increased by approximately 4 million barrels and 3 million barrels for the three and nine month periods ended September 30, 2010 compared to the three and nine month periods ended September 30, 2009 at these facilities.

- Other During the nine months ended September 30, 2010, we recognized approximately $6 million related to volumetric gains. Volumetric gains were immaterial for the nine months ended September 30, 2009.

Field Operating Costs and General and Administrative Expenses. Field operating costs (excluding equity compensation charges) increased in most categories during the three and nine months ended September 30, 2010 compared to the three and nine months ended September 30, 2009 primarily due to (i) our continued growth through additional tankage placed into service during 2009 and 2010 at some of our major terminal locations and (ii) acquisitions such as the PNGS and natural gas processing acquisitions completed in second and third quarters of 2009. Our continued growth through such acquisitions also was the primary reason for the increase in our general and administrative expenses (excluding equity compensation charges) for the same comparative periods.

Equity Earnings in Unconsolidated Entities. Equity earnings in unconsolidated entities decreased in the three and nine months ended September 30, 2010 over the three and nine months ended September 30, 2009 due to the PNGS acquisition in September 2009 that increased our interest from 50% to 100%.

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Supply and Logistics Segment

The following table sets forth the operating results from our supply and logistics segment for the periods indicated:

Operating Results (1)	**Three Months Ended September 30,**		**Three Months Favorable/ (Unfavorable) Variance**		**Nine Months Ended September 30,**		**Nine Months Favorable/ (Unfavorable) Variance**	
(in millions, except per barrel amounts)	**2010**	**2009**	**$**	**%**	**2010**	**2009**	**$**	**%**
Revenues	$ 6,179	$ 4,645	$ 1,534	33%	$ 17,993	$ 11,877	$ 6,116	51%
Purchases and related costs (2)	(6,104)	(4,534)	(1,570)	(35)%	(17,625)	(11,389)	(6,236)	(55)%
Field operating costs	(49)	(45)	(4)	(9)%	(144)	(139)	(5)	(4)%
Equity compensation expense - operations (3)	(1)		(1)	N/A	(1)	(1)		%
Segment G&A expenses (excluding equity compensation expense)	(18)	(17)	(1)	(6)%	(56)	(51)	(5)	(10)%
Equity compensation expense - general and administrative (3)	(5)	(5)		%	(15)	(15)		%
Segment profit	$ 2	$ 44	$ (42)	(95)%	$ 152	$ 282	$ (130)	(46)%
Maintenance capital	$ 3	$ 1	$ (2)	(200)%	$ 6	$ 5	$ (1)	(20)%
Segment profit per barrel (4)	$ 0.03	$ 0.65	$ (0.62)	(95)%	$ 0.68	$ 1.30	$ (0.62)	(48)%

Average Daily Volumes (5)	**Three Months Ended September 30,**		**Three Months Favorable/ (Unfavorable) Variance**		**Nine Months Ended September 30,**		**Nine Months Favorable/ (Unfavorable) Variance**	
(in thousands of barrels per day)	**2010**	**2009**	**Volumes**	**%**	**2010**	**2009**	**Volumes**	**%**
Crude oil lease gathering purchases	622	602	20	3%	615	619	(4)	(1)%
LPG sales	73	61	12	20%	87	88	(1)	(1)%
Waterborne foreign crude oil imported	91	46	45	98%	79	54	25	46%
Refined products sales	48	32	16	50%	43	34	9	26%
Supply & Logistics segment total	834	741	93	13%	824	795	29	4%

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(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of approximately $5 million and $13 million for the three and nine months ended September 30, 2010, respectively, compared to $4 million and $8 million for the three and nine months ended September 30, 2009, respectively.

(3) Equity compensation expense related to our equity compensation plans. See Note 8 to our Condensed Consolidated Financial Statements for additional discussion of our equity compensation plans.

(4) Calculated based on crude oil lease gathering purchased volumes, refined products volumes, LPG sales volumes and waterborne foreign crude oil imported volumes.

(5) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

The absolute amount of our revenues and purchases increased in the three and nine months ended September 30, 2010 as compared to the three and nine months ended September 30, 2009, primarily resulting from higher commodity prices experienced in the 2010 period. The NYMEX benchmark price of crude oil ranged from $71 to $83 per barrel and $59 to $75 per barrel during the three months ended September 30, 2010 and 2009, respectively, and from $64 to $87 per barrel and $34 to $75 per barrel during the nine months ended September 30, 2010 and 2009, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and sale, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those purchases and sales will not necessarily have a corresponding increase or decrease.

Generally, we expect a base level of earnings from our supply and logistics segment that may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. In addition, certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Revenues and expenses are translated at average exchange rates prevailing for each month and comparison between periods may be impacted by changes in the average exchange rates.

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Also, our LPG marketing operations are weather-sensitive, particularly during the approximate six-month peak heating season of October through March, and temperature differences from year to year may have a significant effect on financial performance.

Average daily crude oil lease gathering volumes increased by approximately 20,000 barrels per day during the three months ended September 30, 2010 compared to the same period of 2009 primarily due to recent increased third-party drilling activities. Average daily crude oil lease gathering volumes slightly decreased, however, during the nine months ended September 30, 2010 compared to the same period of 2009 primarily due to the elimination of some of our less profitable lease gathering purchases.

Revenues, net of purchases and related costs, for the third quarter of 2010 decreased by approximately $36 million or 32% compared to the third quarter of September 30, 2009 despite our increased volumetric activity primarily due to the net mark-to-market loss of approximately $43 million that was recognized within the third quarter of 2010 compared to a net mark-to-market gain of approximately $11 million that was recognized in the comparable 2009 quarter. This unfavorable variance was partially offset by other factors including (i) more favorable market conditions experienced during the third quarter of 2010 compared to the same prior year quarter and (ii) increased revenues realized as a result of additional volumes received and sold as third-party drilling activities expanded.

Revenues, net of purchases and related costs, decreased by approximately $120 million or 25% for the nine months ended September 30, 2010 as compared to the nine months ended September 30, 2009 primarily due to decreased LPG margins. LPG margins for 2010 were in line with expectations, but 2009 margins were higher than normal due to the liquidation of lower valued inventory following a write down of inventory values during 2008. The 2010 period was also unfavorably impacted by (i) less favorable crude oil quality differentials and (ii) less favorable market conditions. These unfavorable variances for the nine month comparative periods were partially offset by (i) net gains on sales of excess inventory and linefill that were recognized during 2010 and (ii) our mark-to-market activity. During the nine months ended September 30, 2010, we recognized net mark-to-market losses of approximately $6 million as compared to net losses of approximately $34 million during the nine months ended September 30, 2009. Also, although our average daily crude oil lease gathering volumes remained relatively consistent for the nine months ended September 30, 2010 compared to the same period last year, we recognized increased revenues as a result of additional volumes received and sold as third party drilling activity expanded. These higher margin volumes; however, were partially offset by the elimination of some of our less profitable lease gathering purchases as mentioned above.

Such results for both the three and nine months ended September 30, 2010 compared to the three and nine months ended September 30, 2009 were also favorably impacted by foreign currency adjustments. Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, were translated at the prevailing average exchange rate for each month. During 2010, revenues were favorably impacted by the depreciation of the U.S. dollar relative to the Canadian dollar. The average Canadian dollar to U.S. dollar exchange rate for the three-month period ended September 30, 2010 was $1.04 CAD: $1.00 USD compared to an average of $1.10 CAD: $1.00 USD for the three-month period ended September 30, 2009. The average Canadian dollar to U.S. dollar exchange rate for the nine-month period ended September 30, 2010 was $1.04 CAD: $1.00 USD compared to an average of $1.17 CAD: $1.00 USD for the nine-month period ended September 30, 2009.

Field Operating Costs. Field operating costs (excluding equity compensation charges) increased during the three and nine months ended September 30, 2010 compared to the three and nine months ended September 30, 2009 primarily due to an increase in truck-hauled lease volumes which resulted in increased driver commissions, transport fuel costs and third party trucking fees. Additionally, transport fuel costs were negatively impacted in 2010 by higher diesel fuel prices.

General and Administrative Expenses. General and administrative expenses (excluding equity compensation charges) increased during the nine months ended September 30, 2010 over the nine months ended September 30, 2009 consistent with the overall growth of the segment.

Other Income and Expenses

Depreciation and Amortization. Depreciation and amortization expense increased approximately $19 million for the nine months ended September 30, 2010 compared to the nine months ended September 30, 2009, respectively. The increase was primarily the result of an increased amount of depreciable assets resulting from our acquisition activities including PNGS as well as various internal growth projects. The increase in depreciation expense was partially offset by extensions of the depreciable lives of several of our large storage facilities and pipeline systems based on an ongoing internal review.

Interest Expense. Interest expense increased approximately $5 million and $18 million for the three and nine months ended September 30, 2010 compared to the three and nine months ended September 30, 2009, respectively. This increase is primarily due to the collective issuance of approximately $1.8 billion of senior notes (in July 2010 as well as in April, July and September 2009), which was partially offset by the collective retirement of approximately $425 million of senior notes (in August and October 2009).

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Other income, net Other income, net was a loss of approximately $7 million for the three months ended September 30, 2010, compared to income of approximately $12 million for the three months ended September 30, 2009. The loss in the 2010 period is primarily related to the early redemption of our $175 million, 6.25% senior notes. The income recognized in the 2009 period relates to a net gain of approximately $9 million in connection with our PNGS acquisition and a net gain of approximately $2 million related to the foreign currency revaluation of a CAD-denominated interest rate receivable associated with an intercompany note and the impact of related foreign currency hedges.

For the nine month period ended September 30, 2010, other income, net was a loss of $9 million compared to a gain of approximately $17 million for the nine month period ended September 30, 2009. The loss in the 2010 period is primarily related to the early redemption of our senior notes discussed above, as well as the revaluation of contingent consideration related to our PNGS acquisition. The income in the 2009 period is primarily related to the approximately $9 million net gain in connection with our PNGS acquisition, as well as approximately $8 million of net gain related to the foreign currency revaluation of a CAD-denominated interest rate receivable associated with an intercompany note and the impact of related foreign currency hedges (of which approximately $6 million was reclassified from AOCI).

Liquidity and Capital Resources

General

Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil and other products and other expenses, interest payments on our outstanding debt and distributions to our unitholders and General Partner, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses and (iv) repayment of principal on our long-term debt. We generally expect to fund our short-term cash requirements through our primary sources of liquidity, which consist of our cash flow generated from operations as well as borrowings under our credit facilities. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions, through a variety of sources (either separately or in combination), which may include operating cash flows, borrowings under our credit facilities, and/or the issuance of additional equity or debt securities. At September 30, 2010, we had a working capital surplus of approximately $204 million and approximately $1.3 billion of liquidity available to meet our ongoing operational, investing and finance needs as noted below (in millions):

		As of September 30, 2010
Availability under PAA senior unsecured revolving credit facility	$	1,039
Availability under PNG senior unsecured revolving credit facility (1)		179
Availability under PAA senior secured hedged inventory facility		100
Cash and cash equivalants		13
Total	$	1,331

(1) In April 2010, PNG entered into a three year, $400 million senior unsecured revolving credit facility that matures in May 2013. Borrowing capacity under this facility may be limited from time to time due to covenant limitations. See Note 5 to our condensed consolidated financial statements for additional discussion of this credit facility and the *Sale of Noncontrolling Interest in a Subsidiary* section of Note 7 for additional discussion regarding PNG.

We believe that we have and will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a material adverse effect on our financial condition, results of operations or cash flows. See Item 1A. Risk Factors in our 2009 Annual Report on Form 10-K for further discussion regarding risks that may impact our liquidity and capital resources. Usage of the credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

Congress recently enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which includes provisions regarding the use of derivative financial instruments. The scope and applicability of these provisions is not entirely clear and regulations implementing all the various aspects of the Act have not yet been issued. We are currently reviewing the provisions of this legislation and its potential impact on our business, and will continue to monitor the final rules and regulations as they develop.

Cash Flows from Operating Activities

For a comprehensive discussion of the primary drivers of our cash flow from operations, including the impact of varying market conditions and the timing of settlement of our derivative activities, see Liquidity and Capital Resources Cash Flow from Operations under Item 7 of our 2009 Annual Report on Form 10-K.

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Net cash flow provided by operating activities for the first nine months of 2010 was approximately $463 million. The cash provided by operating activities reflects cash generated by our recurring operations, and is also significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During the first nine months of 2010, we increased the amount of our inventory. The increase in inventory was due to both increased volumes and prices and was primarily related to (i) our crude oil contango market storage activities, (ii) our LPG inventory in preparation of the end users increased demand for heating requirements experienced during the winter months, and (iii) our foreign cargo purchase activities. The net increased levels of inventory were financed through borrowings under our credit facilities as well as through our $500 million senior notes that are being used to supplement capital available from our hedged inventory facility.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding acquisitions and internal capital projects, and short-term working capital and hedged inventory borrowings related to our LPG business and contango market activities as well as refinancing of our debt maturities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). As of September 30, 2010, we have $2.0 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. Our July 2010 offering of our $400 million senior notes due September 15, 2015 was conducted under the WKSI Shelf.

Senior Notes. On September 15, 2010, we redeemed all of our outstanding $175 million, 6.25% senior notes that were due in 2015. We utilized our cash on hand and available capacity under our credit facilities to redeem these senior notes.

In July 2010, we completed the issuance of $400 million of 3.95% Senior Notes due September 15, 2015. The senior notes were sold at 99.889% of face value. Interest payments are due on March 15 and September 15 of each year, beginning on September 15, 2010. We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities.

Credit Facilities. During the nine months ended September 30, 2010, we had net borrowings on our revolving credit facilities and our hedged inventory facility in the aggregate of approximately $41 million. The net borrowings resulted primarily from (i) our increased levels of inventory resulting from the favorable contango market structure, (ii) funding our capital program and (ii) the redemption of our $175 million 6.25% senior notes. These borrowing activities were partially offset by repayments that were made on these credit facilities from funds received by the issuance of $400 million of 3.95% senior notes in July 2010.

During the nine months ended September 30, 2009, we had net repayments on our revolving credit facility and our hedged inventory facility in the aggregate of approximately $634 million. These net repayments resulted primarily from (i) the issuances of our $500 million 5.75%, $500 million 4.25% and $350 million 8.75% senior notes in September 2009, July 2009 and April 2009, respectively, and (ii) our March and September 2009 equity offerings.

In October 2010, we renewed our 364-day committed hedged inventory credit facility, which matures in October 2011. The facility has a borrowing capacity of $500 million, which may be increased to $1.2 billion, subject to obtaining additional lender commitments. Borrowings under this facility will be used to finance (i) the purchase of hedged crude oil inventory for storage activities and (ii) foreign import activities.

For further discussion related to our credit facilities and long-term debt, see Cash Flows from Operating Activities above and Liquidity and Capital Resources Credit Facilities and Long-Term Debt under Item 7 of our 2009 Annual Report on Form 10-K.

Capital Expenditures and Distributions Paid to Unitholders and General Partner

We use cash primarily for our acquisition activities, internal growth projects and distributions paid to our unitholders and general partner. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. See Internal Growth Projects above and Acquisitions and Internal Growth Projects under Item 7 of our 2009 Annual Report on Form 10-K for further discussion for such capital expenditures.

Distributions to unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On November 12, 2010, we will pay a quarterly distribution of $0.9500 per limited partner unit. This distribution represented a year-over-year distribution increase of approximately 3.3%. See Note 7 to our Condensed

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Consolidated Financial Statements for details of distributions paid. Also, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Cash Distribution Policy of our 2009 Annual Report on Form 10-K for additional discussion of distribution thresholds.

Upon closing of the Pacific, Rainbow and PNGS acquisitions, our general partner agreed to reduce the amounts due as incentive distributions. See Note 7 to our Condensed Consolidated Financial Statements for details related to the general partner s incentive distribution reduction.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are subject to business and operational risks, however, that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Contingencies

See Note 10 to our Condensed Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. Where applicable, the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to creditworthy entities.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of September 30, 2010 that varied significantly since December 31, 2009 (in millions):

As of September 30, 2010	**2010**	**2011**	**2012**	**2013**	**2014**	**2015 and Thereafter**	**Total**
Long-term debt and interest payments (1)	$ 68	$ 272	$ 962	$ 479	$ 214	$ 5,161	$ 7,156
Leases (2)	$ 24	$ 67	$ 57	$ 38	$ 29	$ 247	$ 462
	$ 2,766	$ 1,162	$ 263	$ 158	$ 149	$ 195	$ 4,693

Crude oil, refined products and LPG purchases (3)	

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at September 30, 2010, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

(2) Leases are primarily for (i) storage, (ii) rights-of-way, (iii) office rent, (iv) pipeline assets and (v) trucks used in our gathering activities.

(3) Amounts are based on estimated volumes and market prices based on average activity during September 2010. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligations for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At September 30, 2010 and December 31, 2009, we had outstanding letters of credit of approximately $68 million and $76 million, respectively.

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Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements as defined by Item 307 of Regulation S-K.

Recent Accounting Pronouncements

See Note 2 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For additional discussion regarding our critical accounting policies and estimates, see Critical Accounting Policies and Estimates under Item 7 of our 2009 Annual Report on Form 10-K.

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Forward-Looking Statements

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and st regarding our business strategy, plans and objectives for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results to differ materially from the results anticipated in the forward-looking statements. These factors include, but are not limited to:

- failure to implement or capitalize on planned internal growth projects;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- the effectiveness of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;
- shortages or cost increases of power supplies, materials or labor;
- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;

- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

- the availability of, and our ability to consummate, acquisition or combination opportunities;

- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;

- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;

- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);

- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;

- the effects of competition;

- interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;

- increased costs or lack of availability of insurance;

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

- the currency exchange rate of the Canadian dollar;

- weather interference with business operations or project construction;

- risks related to the development and operation of natural gas storage facilities;

- future developments and circumstances at the time distributions are declared;

- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and

- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

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Other factors, described herein, or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Risks Factors discussed in Item 1A of our 2009 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included under Item 7A in our 2009 Annual Report on Form 10-K. There have been no material changes in that information other than as discussed below. Also, see Note 9 to our Condensed Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

The fair value of our open derivatives with commodity price risk and the change in fair value that would be expected from a ten percent price decrease are shown in the table below (in millions):

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ (1)	$ 88
Swaps and options contracts	7	$ (14)
LPG and other:		
Futures contracts	(3)	$ 2
Swaps and options contracts	(20)	$ 21
Total Fair Value	$ (17)	

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain written DCP. The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in a manner that allows for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included under the caption Litigation in Note 10 to our Condensed Consolidated Financial Statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2009 Annual Report on Form 10-K. Those risks and uncertainties are not the only ones facing us and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Repurchases of Equity Securities

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Party of Publicly Announced Plans or Programs	Maximum Number (or approximate dollar value) of Units that May Yet be Purchased Under the Plans or Programs
July 1, 2010 - July 31, 2010		N/A	N/A	N/A
August 1, 2010 - August 31, 2010	9,375(1)	$ 61.01	N/A	N/A
September 1, 2010 - September 30, 2010		N/A	N/A	N/A
Total	9,375			

(1) In August 2010, we purchased 9,375 common units from our general partner for an average price of $61.01 per unit. The common units were used to satisfy our obligations with respect to awards that vested under our LTIP Plans.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. [REMOVED AND RESERVED]

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on

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	Form 8-K filed August 22, 2007).
3.5	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).
3.6	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).
3.7	Amendment No. 6 dated September 3, 2009 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 3, 2009).
3.8	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.10	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008, as amended November 2, 2009 (incorporated by reference to Exhibit 3.10 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009).
3.11	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.12	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.13	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.14	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).

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4.6	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.7	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.8	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.9	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.10	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.11	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.12	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.13	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.14	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.15	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.16	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).
4.17	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein, and U.S. Bank National Association as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.18	Eighteenth Supplemental Indenture (3.95% Senior Notes due 2015) dated July 14, 2010 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 13, 2010).
4.19	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).

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10.1	Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to PNG s Current Report on Form 8-K filed on May 4, 2010).
10.2	Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to PNG s Current Report on Form 8-K filed on May 11, 2010).
10.3 **	Form of Transaction Grant Agreement.
10.4	Second Amendment to Second Restated Credit Agreement dated as of October 25, 2010, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed October 28, 2010).
12.1	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101	The following financial information from the quarterly report on Form 10-Q of Plains All American Pipeline, L.P. for the quarter ended September 30, 2010, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations, (ii) Condensed Consolidated Balance Sheets, (iii) Condensed Consolidated Statements of Cash Flows, (iv) Condensed Consolidated Statement of Partners Capital, (v) Condensed Consolidated Statements of Comprehensive Income, (vi) Condensed Consolidated Statement of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

Filed herewith

** Management compensatory plan or arrangement

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By:	PAA GP LLC, its general partner
By:	PLAINS AAP, L.P., its sole member
By:	PLAINS ALL AMERICAN GP LLC, its general partner

Date: November 5, 2010

By: /s/ GREG L. ARMSTRONG
Greg L. Armstrong, *Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)*

Date: November 5, 2010

By: /s/ AL SWANSON
Al Swanson, *Senior Vice President and Chief Financial Officer (Principal Financial Officer)*

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EXHIBIT INDEX

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.5	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).
3.6	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).
3.7	Amendment No. 6 dated September 3, 2009 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 3, 2009).
3.8	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.10	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008, as amended November 2, 2009 (incorporated by reference to Exhibit 3.10 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009).
3.11	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.12	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.13	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.14	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank,

National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).

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4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.6	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.7	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.8	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.9	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.10	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.11	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.12	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.13	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.14	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.15	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.16	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank

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	National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).
4.17	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein, and U.S. Bank National Association as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.18	Eighteenth Supplemental Indenture (3.95% Senior Notes due 2015) dated July 14, 2010 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein, and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 13, 2010).
4.19	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).
10.1	Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to PNG s Current Report on Form 8-K filed on May 4, 2010).
10.2	Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to PNG s Current Report on Form 8-K filed on May 11, 2010).
10.3 **	Form of Transaction Grant Agreement.
10.4	Second Amendment to Second Restated Credit Agreement dated as of October 25, 2010, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed October 28, 2010).
12.1	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101	The following financial information from the quarterly report on Form 10-Q of Plains All American Pipeline, L.P. for the quarter ended September 30, 2010, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations, (ii) Condensed Consolidated Balance Sheets, (iii) Condensed Consolidated Statements of Cash Flows, (iv) Condensed Consolidated Statement of Partners Capital, (v) Condensed Consolidated Statements of Comprehensive Income, (vi) Condensed Consolidated Statement of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

Filed herewith

** Management compensatory plan or arrangement